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SRAT—Distribution Voltage Sags and Reliability Assessment Tool

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***Abstract*—Interruptions to supply and sags of distribution system voltage are the main aspects causing customer complaints. There is a need for analysis of supply reliability and voltage sag to relate system performance with network structure and equipment design parameters. This analysis can also give prediction of voltage dips, as well as relating traditional reliability and momentary outage measures to the properties of protection systems and to network impedances. Existing reliability analysis software often requires substantial training, lacks automated facilities, and suffers from data availability. Thus it requires time-consuming manual intervention for the study of large networks. A user-friendly sag and reliability assessment tool (SRAT) has been developed based on existing impedance data, protection characteristics, and a model of failure probability.**

The new features included in SRAT are a) efficient reliability and sag assessments for a radial network with limited loops, b) reliability evaluation associated with realistic protection and restoration schemes, c) inclusion of momentary outages in the same model as permanent outage evaluation, d) evaluation of the sag transfer through meshed subtransmission network, and e) simplified probability distribution model determined from available faults records. Examples of the application of the tools to an Australian distribution network are used to illustrate the application of this model.

***Index Terms*—Network reliability, object-oriented programming, power distribution, power quality.**

NOMENCLATURE

AR	Autorecloser.
CBEMA	Computer Business and Manufacturing Association developed supply voltage-time curve for safe operation of computers.
DCB	Downstream circuit breaker.
FIT	Fault isolation time.
MAIFI	Momentary average interruption frequency index.
NOTS	Normally open tie switch.
RT	Repair time.
SAIDI	System average interruption duration index.
SAIFI	System average interruption frequency index.
rS_{sag}	Frequency of severe sag under ratio of CBEMA threshold.
S_{sag}	Frequency of severe sag above CBEMA threshold.

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I. INTRODUCTION

DISTRIBUTION system reliability can be divided into two aspects: system adequacy and system security [1], [2]. Adequacy describes the normal state capability of the system to supply customer demands. Security describes the ability of the system to continue to supply the customer in spite of faults in the network. SRAT analyzes the security of distribution system by predicting the response of the network, seen by the customers, to the expected range of faults.

Because voltage sags can cause malfunctioning or tripping of customer equipment it can be seen from the customer viewpoint as an interruption in continuity of service. For many industrial processes there can be a significant loss of production due to the time to fully restore the process to acceptable range; thus the short sag can have similar consequences to a much longer duration of outage. Thus this very important parameter of power quality is important in describing the perceived continuity and is included in the analysis suite SRAT.

There are two main techniques available to assess distribution reliability: time-domain simulation and the analytical evaluation of probability. Simulation is the most flexible method but suffers from uncertainty of precision and sensitivity. The analytical approach can be further divided into categories: a) Markov modeling and b) network modeling. Markov modeling [3] is a well-defined approach, but the main problem is that the number of discrete states rapidly grows and becomes unmanageable in the analysis of real systems.

Network modeling is very popular technique and used by many utilities [4]–[8]. The attraction of the network model is the simplicity of the method and natural similarities with system topology. Network modeling can be further divided into two categories: a) component reliability modeling and b) system reliability modeling. The IEEE Standard 493 "Gold Book" [9] focuses on component reliability modeling and recommends the use of "series and parallel" methodology and minimal cut-set method, which estimates the frequency and duration of load point indices. However, this component reliability modeling cannot incorporate complex protection and restoration schemes and thus is not suitable for optimization analysis of system network reliability aspects such as the provision of alternate supply paths after the fault. System reliability modeling based on zone-branch reliability methodology [10] is able to analyze the system aspects of isolation and protection characteristics of network protective devices. However, this modeling handles only radial-networks and is very difficult to include MAIFI evaluation. Therefore, SRAT has been designed and developed

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based on node/zone branch methodology for widespread applicability to realistic distribution networks (which may include loops) and can generate the usual load point reliability indices, system average reliability indexes, MAIFI, as well as quantifying voltage dip impacts on customers.

II. Methodology

SRAT is developed as a bus-based tree structure. Generally the data are available in the form of line properties. Therefore, SRAT converts all the line data into the bus data and stores the data on the bus, which is on the lower side of the line connection. For example, the probability of line section failure is calculated by multiplication of line section length (length between targeted bus and upstream of targeted bus) and faults/km, and this is stored as a property of the bus. Switch zone based sections are also used in SRAT for faster reliability studies.

When a permanent fault occurs on a feeder (F1) at point P_1, as shown in Fig. 1, customers on feeders F2 and F3 will experience the same voltage sag. Customers designated C_1 on feeder F1 will experience this disruption differently to the rest of the customers (C_2, C_3, and C_4) on the same feeder. A downstream AR of distribution feeder is coordinated with a substation circuit breaker for protection-operation since the downstream AR is usually unable to clear the full fault current. Therefore, if a fault occurs on feeder F1 at point P_1, the main circuit breaker (CB) of feeder F1 will first open to clear the fault. According to the protection coordination, AR will open in the offload condition followed by closing substation circuit breaker. Therefore, the customers C_1, upstream from AR of feeder F1, will experience a momentary interruption. All buses or customers of feeders F2 and F3 will experience a voltage sag with equal depth and duration while the customers of feeder F1 downstream from AR (C_2, C_3, and C_4) will experience a permanent outage. The duration of permanent outage for different customers will vary according to the particular restoration scheme, as discussed later.

When a fault occurs on feeder F2 at point P_2 (Fig. 1), the DCB is able to clear the fault. Therefore, all buses or customers, upstream from the DCB of F2, will not experience any momentary interruption, but these buses or customers will experience a voltage sag. The different buses or customers upstream from the DCB of feeder F2 will experience the sag with different level of depths. Similar to the previous case, all buses or customers of feeders F1 and F3 will experience a sag with equal depth and duration for the fault on P_2 of F2. Of course, only the buses of downstream from the DCB of feeder F2 will experience a permanent outage.

Both sag and reliability are evaluated by putting faults sequentially on every bus in turn. Then the effect on every bus is determined for each fault and is accumulated using a weighting dependent on the probability of the events.

A. Sag Evaluation

When a fault occurs on a feeder F1 at location of P_1 (Fig. 1), the substation circuit breaker will open to clear the fault. A large fault current flows through the faulted path of the feeder F1, which will produce a momentarily voltage depression on the other feeders of that network. This is called the voltage sag. The time taken by the circuit breaker (or relay or fuse) to clear the fault is the duration of sag. In such condition, all customers on the feeder F2 and F3 will experience the same depth and duration of a sag. If fault occurs at point P_2 on feeder F2 (Fig. 1), the downstream circuit breaker clears the fault. In this case, all customers of the feeders of F1 and F3 will experience the same depth of sag. The depth of sag will be different for the customer points between the substation circuit breaker to downstream circuit breaker of feeder F2. When fault occurs at point P5 on the fuse lateral of feeder F3 (Fig. 1), the fuse clears the fault. In such case, the customers of all three feeders except the customers on the fused lateral will experience the sag. The depth of sag will be different at different location of the feeder F3, whereas the customers on the feeders of F1 and F2 will experience the same depth and duration of sag.

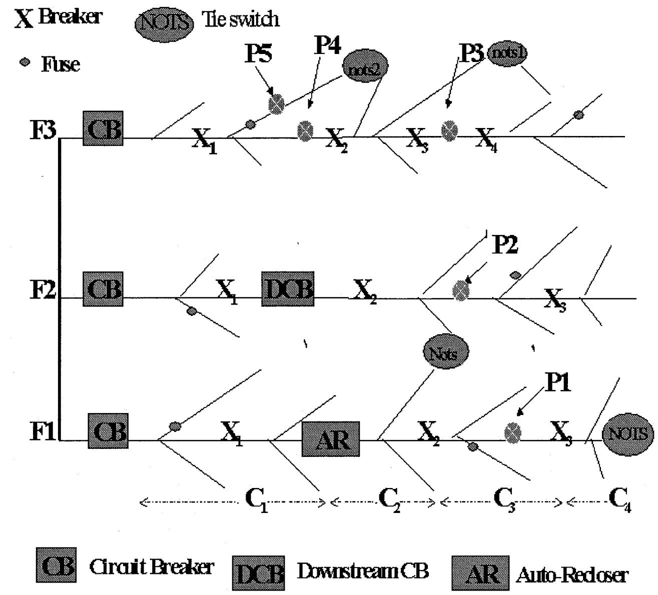


Fig. 1. Schematic diagram for electricity distribution network.

The evaluation of sag depth (V_{sag}) is made based on a impedance divider model [11] as

$$V_{\text{sag}} = \frac{Z_2}{Z_1 + Z_2} \tag{1}$$

where Z_1 is the impedance between the measurement bus and the ideal source point, and Z_2 is the impedance between the fault bus and the measurement bus.

The following assumptions and analysis decisions are currently included in SRAT sag evaluation:

a) different probabilities for different types of faults as: 70% single line ground fault, 15% line-to-line fault, and 15% three-phase faults [3], [12];
b) sags transfer distribution network through subtransmission network;
c) no sags contributed from customer side faults (415 V);
d) 100% probability of success for protection devices/ operations;

e) where multiple protection elements are involved the minimum protection interval is used;

f) zero fault impedance.

The final assumption of zero fault impedance is often untrue, and further data analysis is required to characterize and include this aspect.

All sags are not equally important from the point of view of tripping of customer equipment. A sag event, which is below the CBEMA threshold, is considered as the description of severe sag (S_{sag}). The frequency of S_{sag} is then evaluated for all customer points in the network.

The estimated number of severe sags may be used as an important sag index for the feeders. A different index of sag may be required if a customer's equipment is more tolerant than computers, and may trip less frequently than indicated by the frequency of severe sag. Therefore, a further classification of severity of sags is developed, which is the ratio of CBEMA threshold. The ratio of CBEMA (rS_{sag}) threshold has been estimated as the ratio between the duration of CBEMA threshold and duration of actual sag at same depth. For example

$$rSsag = \frac{DS_{\text{real}}}{DS_{\text{cbema}}} \tag{2}$$

where DS_{real} is the duration of actual sag and DS_{cbema} is the duration of CBEMA threshold at depth of actual sag.

Sag evaluation of an 11-kV network is made as follows. The failure probability of a bus is divided into three different probabilities associated with types of fault, such as single line ground fault, line to line fault, and three-phase fault. Putting a fault on a particular bus with appropriate probability of failure and type of faults, the experienced depth and duration of sag on different buses on the network are evaluated as discussed in the next paragraph. Knowing the zero sequence impedance of lines enables the sag to be determined for all fault types. Note that the sag is calculated for the faulted phases and the overvoltage effect from SLG faults is not currently recorded. The depth is then quantized with the interval value of 0.05 V_{sag} and the duration of sags is quantized in two different groups (these are an interval step of 0.1 when the value is less than one and then an interval step of 1.0). The evaluated frequency of events is accumulated in the appropriate depth-duration bin for all buses of the network.

SRAT estimates the impedance/sag transfer ratio between 11-kV networks through meshed network of 33 kV by the help of upper and lower factorization method. The sag transfer for a fault on a particular network to other adjacent networks is calculated by multiplication of the impedances ratio of other adjacent networks with respect to faulted network and a unit depth of sag at bus bar of faulted network. The effects of sag transfer are evaluated for faults of all buses of all connected 11-kV networks by a 33-kV network.

SRAT also evaluates the frequency of severe sag events and the depth, duration, and frequency of sag events at the customer connection point on the 415 V side of the transformers. The star delta transformer is considered in recording of customer side sag events.

B. Reliability Evaluation Methodology

The frequency of permanent and momentary outages and the duration of permanent outages for a particular bus of a feeder are estimated as follows:

$$P_f(i) = \sum_{j=1}^{N} P_{fi}(j) \tag{3}$$

$$M_f(i) = \sum_{j=1}^{N} M_{fi}(j) \tag{4}$$

$$P_d(i) = \sum_{j=1}^{N} P_{di}(j) \tag{5}$$

where $P_f(i)$, $M_f(i)$, and $P_d(i)$ are the permanent interruption frequency, momentary interruption frequency, and permanent outage duration of ith bus of a feeder, respectively. $P_{fi}(j)$, $M_{fi}(j)$, and $P_{di}(j)$ are the frequency of permanent outage, frequency of momentary outage, and duration of permanent outage are experienced at the ith bus due to a permanent fault on the jth bus, respectively. N is the total number of buses in a feeder. The evaluation of $P_{fi}(j)$ and $P_{di}(j)$ is discussed in Section IV.

In a permanent fault, a line crew is required to determine the faulted bus. The faulted bus is then isolated from the network by opening the nearest air-break-switches. The time required to locate the faulted bus and isolate the faulted bus from the network is called the FIT. Then restoration process starts by restoring power supply from the substation for all upstream buses or customers and all downstream buses or customers are restored if there is a path to back feed from other feeders through normally open tie switches. Sometimes loading demand is higher than the line rating of the other feeders and power supply cannot be fully restored for all downstream buses or customers through available NOTS; this is called partial restoration. All downstream customers and the customers of the faulted segment experience a permanent outage until the repair is complete if there are no NOTS available in downstream segments. For example, when a fault occurs on feeder F1 at P_1 (Fig. 1), the AR will be opened within a short time according to the protection scheme. Then the nearest air-break-switches X_2 and X_3 are opened by the line crew to isolate the faulted bus P_1. After isolation of faulted region, the power supply is restored for the buses or customers between the AR to X_2 by closing of the AR. As well as this, the power supply is restored for all downstream buses or customers beyond X_3 if load demand and line capacity permits, because there is scope to back feed through NOTS. The buses or customers from X_2 to X_3 will experience a permanent outage until the repair is complete. In this case, the customers designated C_3 will experience a permanent outage with duration of FIT plus RT, while the customers designated C_2 and C_4 will experience a permanent outage with duration of FIT only. The number of customers at the ith bus is referred to as C_i.

For the fault on feeder F_2 at point P_2 (Fig. 1), similarly the air-break-switches of X_2 and X_3 are opened to isolate the faulted bus. The power is restored for the customers on the buses between DCB and X_2 by closing of the DCB. The customers beyond X_3 and the customers of faulted region experience permanent outage until the repair is complete, because there are no back-feed options.

Usually, the distribution feeders are connected in a radial pattern. However, we have found that there are some loop connections in real distribution networks. Therefore, a reliability study of loop-connected network has been incorporated in this software. This is implemented here by requiring that any loops can be broken by considering a fictitious tie-switch in a loop and evaluating reliability as a radial network as follows. When a fault occurs on feeder F3 at point of P_3, as usual the air-break-switches of X_3 and X_4 open to isolate the faulted segment and power restores for the buses up to X_3 from the substation. In this case, the loop is separated by a fictitious tie switch of nots1 and power can be restored for the downstream customers beyond X_4 through nots1 in spite of having no real downstream NOTS available. However, when a fault occurs on another loop of feeder F3 at point P_4, the air-break-switches of X_1 and X_2 open to isolate the fault section. In this configuration, this loop breaking fictitious tie switch of nots2 cannot restore power for the downstream customers beyond X_2, because both sides of nots2 do not connect with any power supply.

Normally the SAIFI, SAIDI, and MAIFI are the main quality/reliability indicators. The total customer outage frequency and the total customer outage duration for a feeder are evaluated using the number of customers, the total outage frequency, and the total outage duration of all individual buses as follows:

$$P_{\mathrm{ftot}} = \sum_{i=1}^{N} P_f(i) * C_i \tag{6}$$

$$P_{\mathrm{dtot}} = \sum_{i=1}^{N} P_d(i) * C_i. \tag{7}$$

Then SAIFI and SAIDI are computed using the customer average of the total customer outage frequency (P_{ftot}) and the total customer outage duration (P_{dtot}) respectively as follows:

$$\mathrm{SAIFI} = \frac{P_{\mathrm{ftot}}}{\sum C_i} \tag{8}$$

$$\mathrm{SAIFI} = \frac{P_{\mathrm{dtot}}}{\sum C_i}. \tag{9}$$

Momentary interruption is dependent on the protection coordination schemes in a network. Momentary outage may occur in two ways: a) when the substation circuit breaker is opened for a while to clear the self clearing faults and b) substation circuit breaker opened to coordinate the AR. The total number of momentary interruptions that each average customer can expect is called MAIFI. It has been computed as follows:

$$\mathrm{MAIFI} = \frac{M_{\mathrm{ftot}}}{\sum C_i} \tag{10}$$

where

$$M_{\mathrm{ftot}} = \sum_{i=1}^{N} [M_{fi}(i) + M_{ft}(i)] * C_i. \tag{11}$$

$M_{ft}(i)$ is the total momentary interruption experienced on the ith bus due to transient faults time limited by protection schemes.

III. About SRAT

SRAT is designed and developed based on object oriented design. The software language is chosen of Visual C++ and graphics interfaced by Microsoft Foundation Class (MFC) for the following reasons.

a) C++ has good facilities for complex number calculation.
b) Compiled code is faster than interpreted code.
c) MFC provides powerful graphics tool.

Some of the graphics presentations are made with help gnu plot, which is integrated with this software.

The following features are included in SRAT:

a) sag analysis with frequency of severe sag events;
b) contour plot for all sag events at the start point for all feeders and at any bus point;
c) reliability analysis, namely, SAIFI, MAIFI, SAIDI, and load point indexes;
d) distribution of load point indexes;
e) distribution of SAIDI;
f) zooming of network diagram.

Future development of SRAT will accommodate:

a) distribution of fault impedance;
b) partial transfer of load through NOTS;
c) automation of sag transfer effect through subtransmission network;
d) customer side (415 V) faults and motor start.

IV. Results and Discussions of Case Studies

1) Sag Analysis: One of the key parameters for the assessment of sag and reliability is probability of faults. The distribution of fault probability and average faults/km of distribution feeders was obtained by examining the records of 19 000 faults from 1000 different distribution feeders over three years. These records from one Australian distribution company were found to approximately fit a constant rate of faults/km/year. However a higher fault rate per km is observed for short-length feeders possibly due to higher equipment density. Therefore, a correction factor on the average faults/km is included for short-length feeders.

Four networks consisting of 26 11-kV feeders are studied in this paper. Fig. 2 represents the system topology of Network-2 out of the studied four networks. The symbols used in network configuration are listed in Table I. Key parameters for the results of network analysis are the protection schemes, length of feeder, and system topology. The studied networks differed in the number of air-break-switches from 1.65 per km in Network-1 to 0.66 per km in Network-3. The air-break-switches per km for Network-2 and Network-4 are 0.9 and 1.5, respectively. Close proximity of air break switches can limit the number of customers denied supply for the full duration of the repair. The length of feeders of Network-1 varies from 3 to 50 km, indicating a high expected range of performance for the customers. The range of length in Network-2 is much lower, varying from

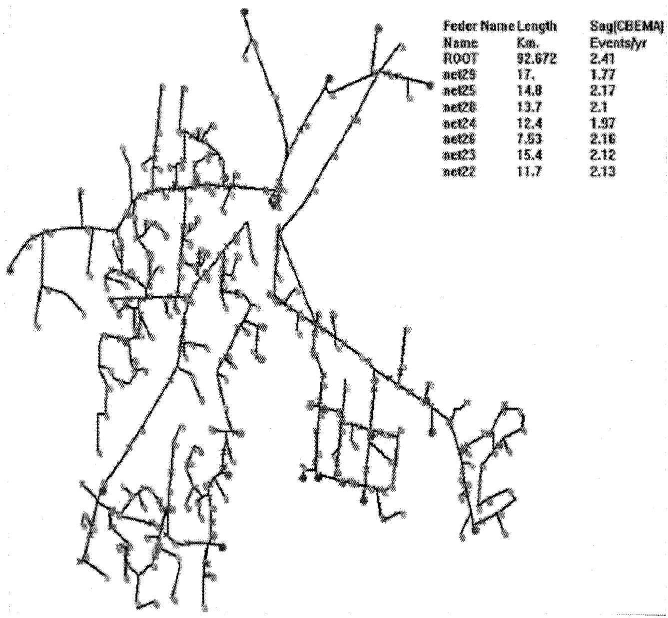


Fig. 2. Network configuration and sag results for Network-2.

TABLE I
SYMBOLS USED IN NETWORK CONFIGURATION

X	Air Break Switch
	Transformer
	Normally Open Tie Switch

12 to 17 Km. One method of increasing the network performance is to increase the number of possibilities of cross supply from other feeders. One 50-km feeder of Network-1 has only 11 NOTS increasing the possibility of alternate supply, whereas one 16-km feeder of Network-2 is only associated with 14 NOTS.

In Fig. 2 we see the computed number of severe sags of each feeder of the network with "ROOT" indicating the composite result for the total network. This immediate calculation does not include the sags due to faults at higher voltage levels in the supply network.

If there is only one circuit breaker on a feeder, then for a fault on that feeder, all other feeders of the network will see the same depth and duration of sags. Buses on the faulted feeder will experience a momentary or extended outage rather than a dip; thus the sag characteristic shown in Fig. 3 will be the same for all buses of the feeder provided there are no other protection devices such as fuses. However, the signature of calculated depth, duration, and frequency of sag events are different for different feeders in a particular network. All of the feeders studied in this paper, except one, are protected by only one circuit breaker at the substation and no studied feeders have any fused laterals. Network-3 is protected by one additional DCB. This gives rise to different signatures of sags upstream from a DCB. The result in Fig. 3 shows the depth-duration-frequency of sag events at a bus bar of Network-4 with overlaid CBEMA curve. This indicates that many of the dips experienced will not be of the severity to cross the CBEMA curve. The software allows this characteristic to be viewed for each bus by right clicking on the bus in the network diagram.

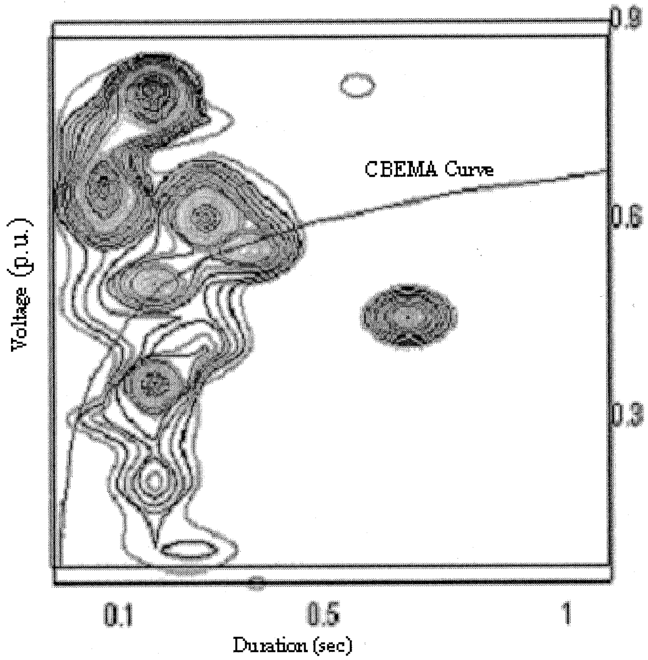


Fig. 3. Contour plot and severe sags in Network-4.

A wide variation of the signature of sags for different studied networks is observed. These variations can be explained in terms of the different protection characteristics for different feeders and the variations of network configuration. Relevant issues include the length and the degree of branching in the network. The network impedances determine the calculated fault current. The amount of fault current and the impedance of the measurement bus from the ideal source point determine the depth of sag. The duration of a sag is determined by the fault current combined with the protection characteristics.

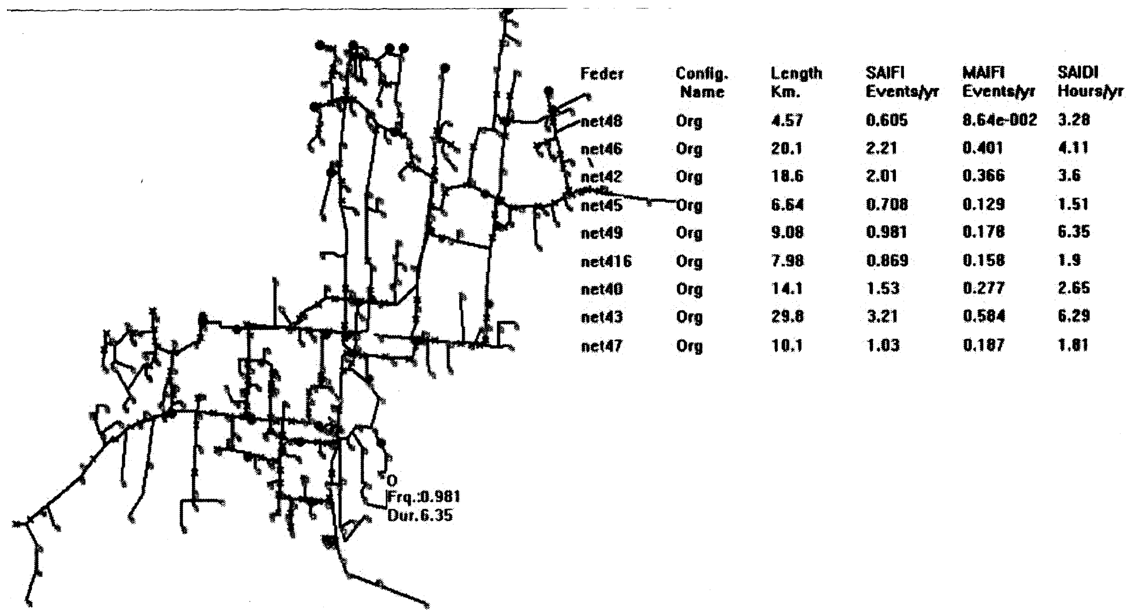
Fig. 4 shows the reliability evaluation results for Network-1.

Network-4 is connected with the other three 11-kV networks through a meshed 33-kV network. Faults in one 11-kV network cause voltage dips at the 33-kV level which transfer to other 11-kV networks. The contribution of sag transfer is dependent configuration of the 33-kV network and impedances.

Table II shows that the contribution of sag transfer through 33-kV network on Network-4 in terms of total number of severe sags. The automation of sag transfer effect is not yet included in SRAT, but with manual intervention, SRAT can evaluate the sag transfer effect.

2) Reliability Analysis: SRAT evaluates the feeder based system average SAIFI, MAIFI, and SAIDI for a network and displays that on the screen as seen in Fig. 4. SRAT also evaluates the load point frequency and duration for the entire network but does not display these automatically, because of the large number of evaluated load point indices. SRAT displays load point indexes for a particular point of a network on request as shown in the lower right of the network of Fig. 4.

The load point frequency for different buses in a feeder is equal for many distribution networks as it is common for feeders



Feder	Config. Name	Length Km.	SAIFI Events/yr	MAIFI Events/yr	SAIDI Hours/yr
net48	Org	4.57	0.605	8.64e-002	3.28
net46	Org	20.1	2.21	0.401	4.11
net42	Org	18.6	2.01	0.366	3.6
net45	Org	6.64	0.708	0.129	1.51
net49	Org	9.08	0.981	0.178	6.35
net416	Org	7.98	0.869	0.158	1.9
net40	Org	14.1	1.53	0.277	2.65
net43	Org	29.8	3.21	0.584	6.29
net47	Org	10.1	1.03	0.187	1.81

Fig. 4. Reliability evaluation results for Network-4.

TABLE II
SEVERE SAG EVENTS BEFORE AND AFTER SAG TRANSFER OF NETWORK-4

Feeder	Length	S_{sag}	S_{sag}
	km.	11kV	Sag Transfer
Root	50.0	3.2	4.8
net48	4.6	3.0	4.7
net46	20.1	2.7	4.3
net42	18.6	2.9	4.6
net45	6.6	3.0	4.7
net49	9.1	2.9	4.5
net416	8.0	2.8	4.5
net40	14.1	2.8	4.4
net438	29.8	2.5	4.1
net47	10.1	2.9	4.5

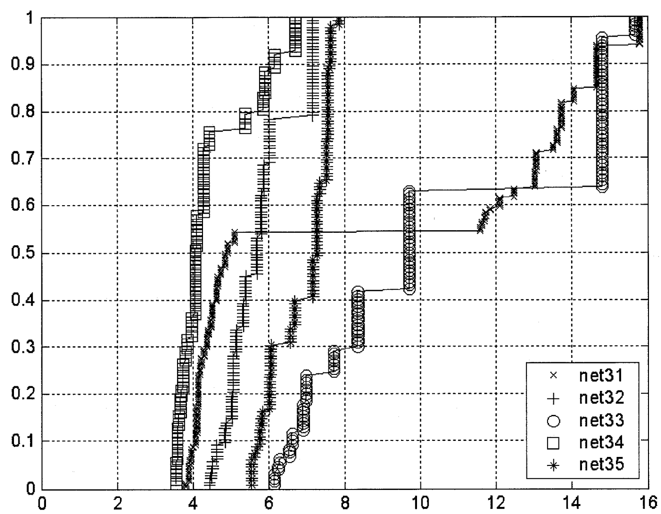


Fig. 5. Ratio of bus duration for different feeders in Network-3.

of a distribution network to be protected by one substation circuit breaker. However, there is a wide variation in the load point duration for different buses in a feeder, because different buses in a feeder are associated with different restoration schemes. SRAT evaluates the cumulative bus depth-duration probabilities of different buses in a feeder. Fig. 5 shows the cumulative probability load point duration of different feeders of Network-3. Notice that the range of duration can vary significantly within one feeder. It is not just the average performance of a feeder which should trigger corrective action but the spread should also be considered. As seen in Fig. 5 even though 50% of customers for net31 experience outages for less than 4 1/2 h, there are still 45% with more than 11 h of outages.

SRAT computes SAIDI by using the average rate of faults/km of permanent outage. In addition, there is a facility included in SRAT for display of the probability distribution of permanent outages. This distribution is determined from the fault records and is used to scale the average SAIDI because of the linear effect of durations. The estimated distribution of SAIDI for five feeders of Network-1 is shown in Fig. 6. The SAIDI distribution curve can assist with the determination of whether a particular performance is in the range expected for a given system topology, restoration, and protection or whether it indicates an abnormally performing feeder. For example, if the observed SAIDI of net13 is measured as five while the expected SAIDI was two, this does not necessarily indicate an abnormally performing feeder, because a SAIDI of more than five for net13 is expected 30% of the time.

A SAIDI value of 15 would be expected less than 8% of the time and would probably indicate abnormal operation. Similarly, if the observed SAIDI of net17 is measured as 15, which would be expected 35% of the time, this would not necessarily indicate abnormal operation.

V. CONCLUSION

SRAT is developing into a powerful tool for sag and reliability assessment of the existing distribution systems. SRAT can

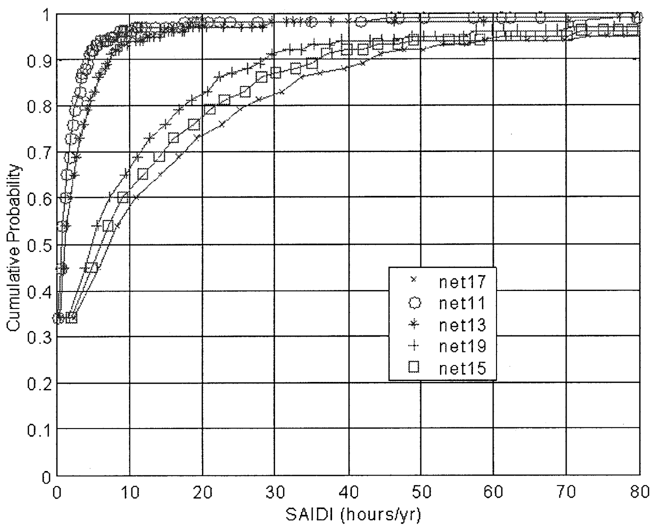


Fig. 6. Variation of SAIDI of Network-1 with probability distribution of faults per kilometer per year.

be used for the assessment of distribution reliability associated with looped networks, complex protection, and restoration elements. The protection and restoration elements include downstream circuit breakers, different types of NOTS, autochange overload restoration and remote load restoration, and partly or fully automated distribution system, etc. Future extensions to the software capability will be eased as it is based on an object-oriented design.

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